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Gone with the Wind? - Electricity Market Prices and Incentives to Invest in Thermal Power Plants under Increasing Wind Energy Supply[1]

Thure Traber[1] and Claudia Kemfert

The increased wind energy supplied to many electricity markets around the world has to be balanced by reliable back up units or other complementary measures when wind conditions are low. At the same time wind energy impacts both, the utilization of thermal power plants and the market prices. While the market prices tend to decrease, the impact on the utilization of different plant types is at the outset unclear. To analyze the incentives to invest in thermal power plants under increased wind energy supply, we develop a computational model which includes start-up restrictions and costs and apply it to the German case. We find that due to current wind supply the market prices are reduced by more than five percent, and the incentives to invest in natural gas fired units are largely decreased. An increased wind supply erodes their attractiveness further. Consequently, a gap between the need for and the incentive to provide flexibility can be expected.

JEL classification: C63, L13, L94, Q42,

Keywords: electricity market modeling; start-up costs; wind energy; oligopoly;

1 Introduction

Today, wind power provides a cheap source of renewable and carbon free electricity in many countries. Modest costs per output produced establish a comparative advantage of wind power over most other renewable energy applications. With fossil prices on the rise, wind power may also be competitive with conventional sources like gas and coal fired power plants. However, in most countries wind power production is not subject to market pricing but to governmentally predetermined tariffs like the German feed-in tariff for renewable energies (FIT). The FIT establishes a guaranteed price for every supplied renewable energy production unit, to be purchased and paid by the established power market participants, and allowed to be passed through to consumers.

Given such support, wind power has experienced a fast development in the last decade in many countries, - especially in Denmark, Germany, and Spain, the US, and China - , and is expected to grow further in the next years. For instance, Lemming et. al (2007) project the current annual 25 percent increase in installed wind power to continue until 2015 reaching a global electricity market penetration of 25 percent by the midst of the century. Other sources project similar figures. For Europe,

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Eurelectric (2007) calculates with 190 Gigawatt of wind power capacity installed in the EU 27 by 2030 in its baseline scenario. In the case of Germany, according to BDEW (2008) almost 40 tera watt hours of wind energy has been produced in 2007, corresponding to about 23 Gigawatt installed. Furthermore, Nitsch (2008) projects a production increase of more than 45 tera watt hours to almost 88 tera watt hours by the year 2020, and a market penetration of wind power in Germany of circa 15 percent.

This development may give rise to problems of reliability of the overall electricity supply because wind power supply fluctuates with day to day meteorological conditions and falls close to zero several times of the year. In addition, electric power can not be stored economically in large amounts. Thus, the more flexible thermal power plant sector has to provide back-up capacity to cope with hours of weak wind load. The question is whether the electricity market will provide incentives to commission appropriate capacities. Two effects of increased wind power are apparent. On the one hand, wind power erodes the prices received by market based thermal power plants. On the other hand, the effect of wind power on the utilization of the thermal power plants are ambiguous. While the demand left for thermal power plants is clearly reduced by the introduction of wind power, the profile of the residual load is changed by wind power generation such that more flexible units like gas turbines might experience an increase of utilization.

The price effect of the introduction of wind power has attracted some attention in the contemporary literature. Rathmann (2007) analyzes the support for renewable energy supply by using a numerical model with varying assumptions on the cost structure which are based on historic fuel price and emission market price data. He shows that renewable energy support can reduce electricity wholesale prices for certain parameter values. Bode and Groscurth (2006) use a similar model of the German power sector with exogenous emission pricing and find a negative price effect for some consumers which are partially exempted from the burden of the RES support. Traber and Kemfert (2009) apply an oligopolistic market model and include an endogenous emission price determination. They find significant feed backs of the emission market since the promotion of renewable energy slackens the emission market price signals. Hence, two effects of renewable energy support dampen electricity producer market prices: a substitution effect which reduces the demand for conventional emission intensive sources and an emission price effect which reduces conventional production costs. Furthermore, they investigate the consumer side of the market[2] and find that the price dampening effect of the emission price reduction is overcompensated by the price increasing burden related to the support of RES. However, a criticism directed to these models is that they do not account for start-up peculiarities which is discussed as an important topic when analyzing the impacts of fluctuating renewable energy supply[3].

Unfortunately, start-up costs increase the analytical effort to model cost min-

[2]In the present paper we focus on the supply side of the market, and therefore ignore effects induced by the support mechanism on the consumer side.

[3]The importance of the flexibility of thermal power plants for the integration of wind power has been pointed out by several studies. See for instance DENA (2005) or Oswald et al. (2008).

imization on the producer side, since they add a fixed cost component which is independent of the subsequent utilization of started-up power plants. The problem is also known as unit commitment problem which is often analyzed as (mixed) integer programming (IP) problem. For a thorough description of this type of models see Hogan (2003). A major disadvantage of IP models is, however, their computational effort. In addition, solvability for large systems is not guaranteed. Alternatively, one can use linear programming (LP) models. These models can be much easier computed but they have to sacrifice some accuracy, since they are not able to cope with non convexities arising from decreased part load efficiencies. For a recent example see Kuntz and Müsgens (2007).

Some studies analyze the German market in particular. Assessing market power on the German power market, Weigt and Hirschhausen (2008) account for the costs induced by start-up processes with a model that combines two optimization stages. First, a MIP is used to solve the unit commitment problem, and, second, an optimization with fixed binary plant status variables taken from the first step is used to find the actual dispatch, i.e. production of electricity. They find significant deviations from the historic market outcomes, amounting on average to mark-ups of eleven percent in baseload, and to almost thirty percent in peak load periods. In the field of the analysis of effects of wind power support on market prices Sensfuß et al. (2008) use a so-called agent based simulation platform which also accounts for start-up costs. They find price reducing effects of about 0.7 Euro cent due to 52.2 tera watt hours renewable energy supply for Germany in 2006.

In the models with start-up costs mentioned sofar, conventional electricity production will be completely crowded out by any RES since they are in principal load fulfilment models. However, with a comparatively high fraction of heavy industry consumers with high electricity cost shares as well as options to reduce consumption, and, given the rather close connections to adjacent markets in the European neighborhood, some elasticity of demand has to be accounted for. A notable example is provided by Müsgens (2006) who uses a linear model (LP), includes international trade in electricity and finds significant exertion of market power on the German market in peak load hours. However, to our knowledge the models applied sofar are not able to account for market power and start-up effects at the same time.

With the present paper, we try to fill this gap in the literature and present a simple model that incorporates start-up costs in a market framework with elastic supply and demand. Together with the wholesale market price effects of the wind power supply, we study the incentive to invest in thermal power plants. Abstracting from non convexities and potential differences between start up state and actual dispatch of power plants, we develop the mixed complementary programming (MCP) model ELECTRICITY SUPPLY AND DEMAND MATCH under EMISSION TRADING and RENEWABLE ENERGY (ESYMMETRY). Similar to many other approaches to investigate electricity markets, e.g. Lise et. al (2006), Traber and Kemfert (2007), Bushnell et al. (2008), the model can assess different market behavior of important electricity suppliers: On the one hand, price taking perfect competitive behavior of all market participants, and, on the other hand, Cournot quantity setting behavior of large firms under competition of a price taking aggregate of fringe firms.

In the following section 2 we describe the mathematical model. In section 3 we introduce the technologies available to conventional power producers in Germany, and demonstrate the calibration of the model. Section 4 reports results in regard to prices, emissions, electricity production mix, and the incentives of firms to invest in new thermal power plants. Finally, section 5 summarizes the results and concludes.

2 Model

The representative firm i maximizes profits from plant operation, i.e. revenues net of production costs, regarding fixed costs as sunk. In each period t of the limited[4] time horizon T, the firm's revenues are the product of its production of electricity in all plants, $q^{i,t}$, and the market price, determined by the inverse demand $P^t(Q^t)$, and the aggregate production Q^t of all firms.

We regard a set of conventional production technologies N and denote a single technology as n. The costs associated with the production of $q^{i.t.n}$ in technology n of firm i are assumed to be decomposable into a part that applies independently from the load profile to all produced units, and a part which depends only on start-up processes, i.e. the load gradient $l^{i,t,n}$. The two parts of the costs are denoted as variable costs, $C^{i,t,n}(q^{i,t,n})$, and start-up costs, $S^{i,t,n}(l^{i,t,n})$, respectively, where the load gradient is defined as:

$$l^{i,t,n} \equiv \begin{cases} \frac{q^{i,t,n}-q^{i,t-1,n}}{\overline{q}^{i,n}} & \text{if } q^{i,t,n} > q^{i,t-1,n} \\ 0 & \text{otherwise} \end{cases} \quad \forall t \in T, \forall i \in I, \forall n \in N. \tag{1}$$

The start-up costs of a period t grow with the load gradient. Therefore, any load increase in one period will weakly decrease the start-up costs in the following period. More precisely, the start-up costs of firm i in period t and technology n, $S^{i,t,n}$, are assumed to be linear in the load gradient: $S^{i,t,n}(l^{i,t,n}) = S^n l^{i,t,n}$, where S^n denotes the start up cost coefficient. The variable costs are linear in output and, hence, can be written as: $C^{i,t,n}(q^{i,t,n}) = C^n q^{i,t,n}$.

In addition, the load gradient is restricted to the maximum load gradient, $\overline{l}^n$, in accordance with the technical characteristic of the technology. For instance, steam turbines take considerably longer lead times to reach full load compared to gas turbines. Finally, the load of every firm is in every period and technology restricted to her maximum available capacity, $\overline{q}^{i,n}$, i.e. the product of installed capacity $q^{cap,i,n}$ and availability a^n.

The inequality-restricted profit optimization problem of firm i can be expressed

[4] The optimization is applied to a single week. Thus, discounting may be neglected.

as:

$$
\begin{aligned}
\max_{\vec{q}^i} L^i = \quad & \sum_{t=1}^{T} P^t(Q^t) q^{i,t} - \sum_{t=1}^{T}\sum_{n=1}^{N} C^n q^{i,t,n} - \sum_{t=1}^{T}\sum_{n=1}^{N} s^n l^{i,t,n}, \\
& \text{s.t.} \\
& \bar{l}^{i,n} \geq l^{i,t,n},\ \forall t \in T, \forall n \in N, \text{and} \\
& \bar{q}^{i,n} \geq q^{i,t,n},\ \forall t \in T, \forall n \in N,
\end{aligned} \tag{2}
$$

where $\vec{q}^{\,i}$ denotes the time profile of production of firm i. The central first order condition with regard to production in technology n of oligopolistic firm i in period t in a Nash-equilibrium can be written as:

$$
\frac{\partial L}{\partial q^{i,t,n}} = P'^t(Q^t) q^{i,t} + P^t(Q^t) - C^n - S^n \frac{\partial l^{i,t,n}}{\partial q^{i,t,n}} - \lambda^{i,t,n} + S^n \frac{\partial l^{i,t+1,n}}{\partial q^{i,t,n}} + \lambda^{i,t+1,n} - \kappa^{i,t,n} \leq 0, \tag{3}
$$

where $\lambda^{i,t,n}$ and $\kappa^{i,t,n}$ denotes the shadow price of the load gradient restriction and the capacity restriction respectively. Furthermore, the first derivative of the inverse demand is denoted as $P'^t(Q)$.

Small firms regard the price as independent of their output decision, and, thus, their first order condition boils down to

$$
\frac{\partial L}{\partial q^{i,t,n}} = P^t(Q^t) - C^n - S^n \frac{\partial l^{i,t,n}}{\partial q^{i,t,n}} - \lambda^{i,t,n} + S^n \frac{\partial l^{i,t+1,n}}{\partial q^{i,t,n}} + \lambda^{i,t+1,n} - \kappa^{i,t,n} \leq 0. \tag{4}
$$

Under perfect competition (4) would represent the behavior of all firms. In the following section we report results that are generated either under the assumption of an oligopolistic market or, alternatively, under perfect competition, and discuss which representation is more appropriate by comparing with historic spot prices from the European Energy Exchange (EEX) in Leipzig. But first, the data for the technology parameters will be introduced.

3 Cost Functions, Data and Calibration

The time and firm invariant constant marginal costs of technology n are

$$
C^n = \frac{p^n + \sigma e^n}{\eta^n} + oc^n,\ \forall n \in N, \tag{5}
$$

where σ denotes the emissions price, and p^n, e^n, η^n and oc^n denote the fuel price, the fuel emission, the degree of efficiency, and the variable operation and maintenance costs of technology n respectively.

The start-up costs $S^{i,t,n}$ are, by contrast, not only depending on the used technology, but on the period t and the firm i. The marginal start-up costs of technology n in period t of firm i which are determined by start-up fuel requirement,sf^n, and increased depreciation due to start up, d^n, are:

$$S^n = sf^n(p^n + \sigma e^n) + d^n,\ \forall n \in N. \tag{6}$$

The main technologies of conventional producers are hydro (HYD), large and small nuclear (NUCL L, NUCL S), old and new brown coal (BC Old, BC New), old and new hard coal (HC Old, HC New), natural gas combined cycle (NG CC), natural gas steam and gas turbines (NG ST, NG GT), and heavy oil steam and gas turbines (O ST, O GT). Their parameters are taken from DENA (2005) or based on own information and are outlined in Table 1.

	fuel price	fuel emission	efficiency	o&m costs	start-up fuel	start-up depreceation	maximum load gradient	availability
	p	e	η	oc	sf	d	$\bar{\imath}$	a
	[cent/kWh]	[kg/kWh]	[%]	[cent/kWh]	[kWh/kW]	[cent/kW]	[%/hour]	[%]
HYD	0,00	0,00	1,00	0,26	0,0	0,00	100	0,75
NUC L	0,21	0,00	0,34	0,04	16,7	0,17	4	0,86
NUC S	0,21	0,00	0,32	0,10	16,7	0,17	4	0,86
BC New	0,45	0,40	0,43	0,26	6,2	0,30	8	0,85
BC Old	0,45	0,40	0,34	0,26	6,2	0,10	8	0,85
HC New	0,72	0,34	0,43	0,20	6,2	0,50	14	0,82
HC Old	0,72	0,34	0,34	0,20	6,2	0,15	14	0,82
NG CC	2,17	0,20	0,58	0,13	3,5	1,00	50	0,86
NG ST	2,17	0,20	0,40	0,15	4,0	1,00	50	0,86
NG GT	2,17	0,20	0,35	0,15	1,1	1,00	100	0,86
O ST	1,72	0,28	0,38	0,15	4,0	0,50	50	0,84
O GT	1,72	0,28	0,33	0,15	1,1	0,50	100	0,84

Table 1: Technology parameters.

Furthermore, for the representation of the supply side, we utilize plant data of four major electricity producers, - EnBW, E.ON, RWE, Vattenfall - , and minor producers aggregated to a set of fringe firms as reported in Table 2. This ownership representation is based on a multiplicative calculation of ownership shares in power plants owned by the large firms.

To obtain the seasonal available capacities of the firms, installed capacities have to be multiplied with seasonal availability factors of the four seasons[5]: winter from November until February, spring from March until April, summer from May until August, and autumn from September until October. We weighted the annual availabilities documented in Table 1 with 6/7 to represent summer and autumn, and with 8/7 for winter and spring.

The model is applied to simulate a single week. To study a complete year from November 2007 until October 2008, we calculate four weeks which had a wind yield that was close to the seasonal average wind production in the respective period. The winter 2007 - 2008 is represented by the week from 3rd of February until 9th of February 2008, spring 2008 by the week from 28th of March until 3rd of April 2008, summer 2008 by the week from 28th of June until 3rd of July 2008, and autumn

[5]The seasonal disaggregation is chosen in line with DENA (2005).

q^{cap}			net MW installed		
	EnBW	E.ON	RWE	Vattenfall	Fringe
HYD	427	1507	638	0	893
NUC L	3286	7639	3536	904	906
NUC S	733	0	0	514	51
BC New	404	974	1074	3639	217
BC Old	0	346	7544	3664	192
HC New	495	2585	1288	1194	2157
HC Old	2179	7348	3165	473	3979
NG CC	357	417	939	760	2598
NG ST	260	2384	1416	423	1877
NG GT	427	1070	627	920	2073
O ST	328	1476	19	259	287
O GT	112	7	2	387	254

Table 2: Installed net electric production capacities of the German electricity sector.

2008 by the week from 8th until 14th of September 2008. The emission permit prices for these weeks complete the input for the supply side. They are taken from the download section of EEX and have been 0.025, 22, 27.5 and 23 euro per ton of CO_2 for the chosen weeks in winter, spring, summer and autumn respectively.

The demand side is represented by periodic iso-elastic demand which can be written as $D^t(P^t) = D_0^t \left(\frac{P_0^t}{P^t}\right)^{-\epsilon}$, where ϵ denotes the price elasticity, and D_0^t and P_0^t reference values of demand and price respectively. Their values are the realized periodic market demands from the download section of the UCTE[6], and seasonal hourly average EEX prices respectively. Following the strategy of Green and Newbery (1992), we try to fit the model as close as possible to historic spot market values. Therefore, the model is calibrated by the choice of the periodic demand elasticity. We apply either constant elasticities over all periods or periodic elasticities that are inversely related to the seasonal average hourly EEX prices. The latter assumption is based on the economic logic that possibilities to substitute supply, e.g. by demand reduction of industrial consumers or increased imports, should be more scarce in peak load hours and more abundant in weak load hours.

Table 3 documents the calibration procedure for the selected spring-week in terms of the coefficients of correlation, the average difference of EEX-spot-price to model price, and the mean of the absolute deviation of model prices and EEX prices. The first four rows list the respective results for constant demand elasticities between 0.6 and 0.9, while the last four rows show the results for hourly elasticities of demand that are the four- to sevenfold of the inverse of the seasonal average hourly EEX prices. When we compare the model accuracy under the assumption of oligopolistic competition to that of perfect competition, we find that the former achieves better performance in terms of the difference and deviation from the historic EEX-prices while the latter assumption achieves a better coefficient of correlation.

However, the assumption of perfect competition generates prices that are at av-

[6]Union for the co-ordination of transmission of electricity, www.ucte.org/resources/dataportal/

	Oligopolistic Competition			Perfect Competition		
	R	difference	deviation	R	difference	deviation
elasticity						
0,6	0,933	-6,9%	13,7%	0,933	14,2%	18,9%
0,7	0,932	-2,7%	13,1%	0,937	13,2%	17,9%
0,8	0,929	-0,1%	13,2%	0,937	12,5%	17,1%
0,9	0,929	1,4%	13,1%	0,936	11,9%	16,5%
scaling factor of elasticity						
4	0,934	-7,5%	11,3%	0,935	15,1%	19,3%
5	**0,933**	**0,0%**	**11,2%**	0,939	14,2%	18,4%
6	0,932	3,3%	12,2%	0,940	12,7%	16,9%
7	0,933	4,7%	12,6%	0,938	11,7%	16,0%

Table 3: Coefficients of correlation, difference of EEX-spot-price to model price, and mean deviation of model price to EEX prices.

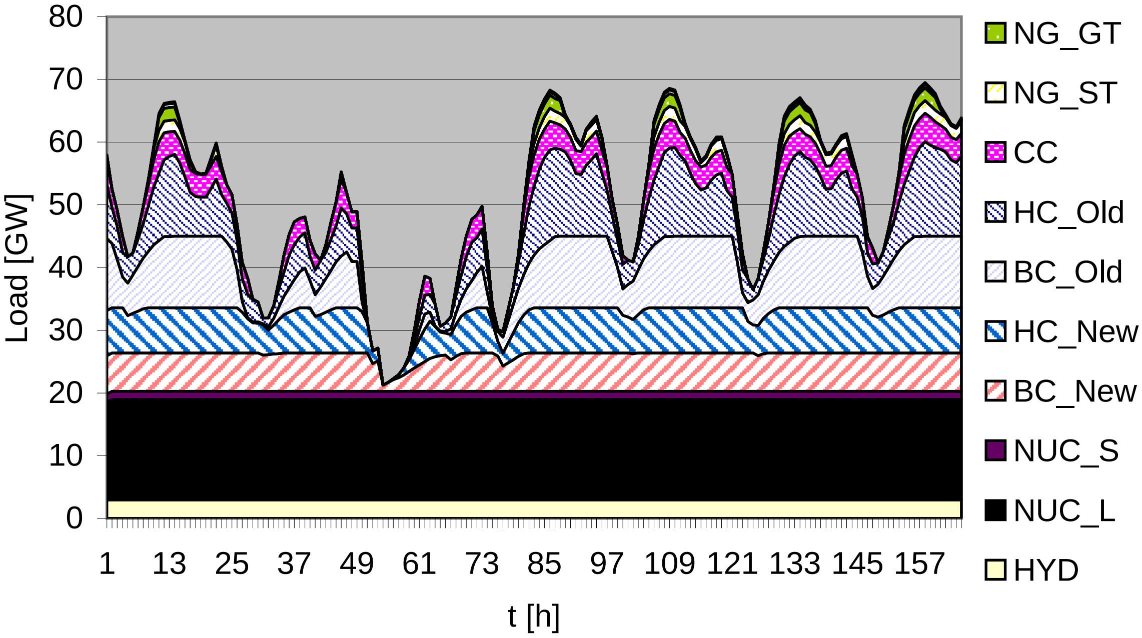
erage around 13 percent lower than the EEX prices, while assuming oligopolistic competition may yield price simulations that at average hit the EEX-price history. Since both behavioral assumptions yield acceptable Rs of above 0.9, imperfect competition seems to be more adequate to model the German market with our cost assumptions, and is therefore assumed in the following.

Comparing the setting with constant elasticities to the setting with hourly elasticities we find rather modest differences in regard to R and the average difference from the historic EEX-prices, but the average deviation of model results is significantly decreased to even below eleven percent. These best values achieved are based on periodic elasticities that are the inverse of the seasonal average hourly EEX prices in euro cent per kWh multiplied by a scaling factor of five, and are highlighted bold in Table 3. This assumption yields elasticities around one, i.e. elastic demand in the base load hours and inelastic demand in peak load hours. Figure 1 below highlights the outcome of the calibration in regard to plant dispatch and prices respectively.

The same calibration procedure has been applied to the representative weeks in winter, summer, and autumn 2008. We found that hourly elasticities with scaling factors of 7 for winter, 8 for spring, and 5 for the summer achievs best values to replicate the history of EEX prices.

4 Results

We develop our results by calculating three counterfactual scenarios together with the analysis of the baseline scenario under current conditions termed *Real Wind* (RW). First, scenario *Baseload Wind* (BW) is chosen to demonstrate the effects that are induced in the baseline scenario RW by the fluctuation of wind energy output, and assumes that the energy output of wind turbines would be supplied constantly with its weekly average. Second, we calculate the counterfactual *No Wind* (NW) where no wind energy is supplied and all load is matched by conventional power



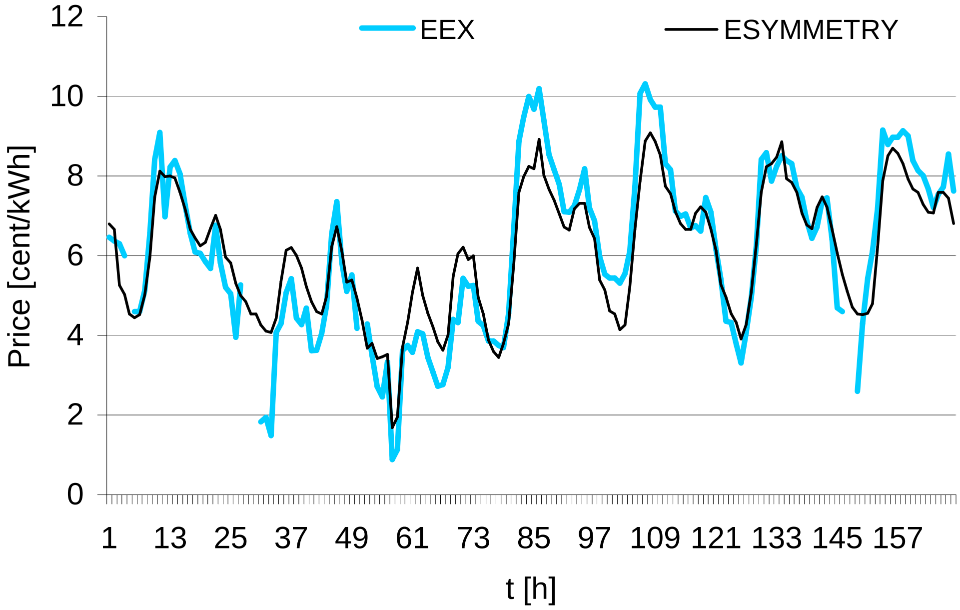


Figure 1: Plant dispatch (top), and EEX and model prices (below) in the representative spring week.

units. Thirdly, we calculate the scenario *Advanced Wind* (AW) that assumes a doubling of the realized hourly wind power supplied in the representative weeks in order to calculate the impact of the projected wind energy supply increase.

Table 4 reports the results with regard to the volume weighted average price level, the emissions and the supply of wind and conventional power, where the results for the representative weeks are transformed by the seasonal weights to get annual values. The baseline scenario *Real Wind* yields an average price level of 6.9 cent, emissions of 344 million tons of CO_2[7], and a total supply to German consumers of 510 tera watt hours. Wind power supplies account for 42.5 tera watt hours or more than eight percent of total supply. Furthermore, we show the changes that are induced by the current wind supply of the scenarios *Baseload Wind* and *Real Wind* compared to the scenario *No Wind*, and the change expected to be induced by the increased wind supply of scenario *Advanced Wind* compared to scenario *Real Wind*.

If we first consider the changes induced by the scenario *Real Wind* compared to *No Wind* documented in the center column of the bloc on the right of Table 4, we find that the price level is reduced by 0.37 euro cent or more than five percent. In addition, the emissions decreased by $13,6$ million tons of CO_2 while the supply increased by 27.3 tera watt hours. The supply effect comprises of the additional wind power supply of 42.5 tera watt hours and the reduction of conventional power plants by 15.2 tera watt hours. In other words, only a little more than one third of wind power supply has led to a crowding out of conventional resources[8]. As a consequence the saved emissions are comparatively small: each kilo watt hour has reduced emissions at average by only 320 gram of CO_2 while the average emission of the conventional production is more than 670 gram of CO_2. If we take the FIT for wind power of currently 9 cent as implied in BDEW (2008) and the market price for electricity as cost indicators, the according marginal abatement costs of wind power are almost 66 euro per ton of CO_2.

Nonetheless, the emission reductions of *Real Wind* are higher than those that would have been caused by a constant supply of wind power. The first column of the bloc on the right hand side of the table shows the induced change by the *Baseload Wind* scenario. In this setting the price reduction and the supply increase would have been more pronounced, and consequently, the emission reduction would have been smaller. The intuition behind this result is that the increased start up processes drive prices more than emissions. Combined, both effects increase the marginal abatement costs of wind power to more than 69 euro per ton of CO_2. The comparison with the *Real Wind* and the *Advanced Wind* scenario, however, reveals only a comparatively small importance of the effects due to the fluctuation of wind.

The last column of Table 4 shows the changes due to the doubling of wind power, i.e. the *Advanced Wind* scenario, in comparison with the current situation. It

[7]The calculated emissions of the electricity sector appear to be rather high when compared to other sources, e.g. Nitsch (2008), since they include the emissions related to combined heat and power production.

[8]The support of renewable energy by the German FIT has an additional effect on the demand side due to increased consumer prices. These effects are not considered here. For a detailed analysis of these effects see Traber and Kemfert (2009).

emerges that the price level decreases by another third of a cent, and that the emission are additionally reduced by more than 17 million tons of CO_2. At the same time supply is almost 23 tera watt hours higher while the crowding out of conventional supply is 19.6 tera watt hours. Thus, compared to the changes induced by the current wind power supply, the advanced wind power supply yields an higher crowding out of conventional supply and a significantly enhanced emission reduction per supply, i.e. 400 gram of CO_2 per kilo watt hour. Thus, the according marginal abatement costs of wind power at current support tariff is reduced to 60 euro per ton of CO_2. This finding can be explained by a successively higher crowding out of coal fired plants as more wind power is supplied.

Scenario		NW	BW	RW	AW	BW	RW	AW
						Change compared to		
						NW		RW
Price level	[cent/kWh]	7,27	6,86	6,90	6,57	-0,41	-0,37	-0,33
CO_2	[MT]	357,1	344,0	343,6	326,4	-13,1	-13,6	-17,1
Supply	[TWh]	482,3	509,6	509,5	532,4	27,4	27,3	22,9
of which								
- Wind		0,0	42,5	42,5	85,0	42,5	42,5	42,5
- Conventional		482,3	467,1	467,0	447,4	-15,1	-15,2	-19,6

Table 4: Prices emissions and supply in the scenarios together with induced changes.

In the remainder of the paper we analyze the question whether the market expectations will provide the signals for investments in power plants that are needed to provide sufficient back up capacities for the fluctuating wind power supplies. Therefore, we compute the incentive to invest as the difference between the average shadow price of the capacity restriction and the investment costs per output of the different technologies. Note that in our oligopolistic setting the shadow prices of the capacity restriction varies over firms while the investment costs are the same for all investors. In line with EWI/EEFA (2008), we adopt investment costs of 1.5, 1.3, 0.7, and 0.2 euro cent per kilo watt hour for new brown coal, new hard coal, natural gas fired combined cycle and simple gas turbines respectively.

In Table 5 we report the incentives to invest for those technologies that are relevant for the German market[9]. In a perfect competitive market the incentive to invest at given prices are equal to the ones reported for fringe firms in the lower rows of the Table 5. We find that for all technologies the incentives to invest decrease with the development of wind supply. Notably, the flexible gas turbines loose half of their attractiveness relative to the *No Wind* scenario and are always dominated by hard coal and brown coal as well as combined cycle gas turbine investments. Combined cycle gas turbines experience a reduction of incentive to invest by almost thirty percent, while coal based units experience a reduction of only about one fourth.

[9]Large scale hydro power is not a relevant investment since suitable sites are completely developed. In addition, nuclear is not an option due to the political decision on the phase out of nuclear energy in Germany.

Thus, for firms which act perfect competitively, investments in more flexible natural gas based units are not only dominated by coal fired base load units, but loose competitiveness with the development of wind power. This development will increase the gap between the incentives to invest in flexible units and the need of these units. These findings suggest that the market is not likely to cope with the FIT based wind energy increase.

Incentive to invest [cent/kWh], Relative change of AW against NW [%]

	BC	HC	CC	NG GT
EnBW				
NW	1,5	1,4	1,0	0,2
RW	1,2	1,1	0,7	0,1
AW	1,1	0,9	0,6	0,0
	-30%	-33%	-41%	-85%
E.ON				
NW	0,6	0,4	0,1	0,0
RW	0,3	0,2	0,0	0,0
AW	0,0	0,0	0,0	0,0
	-100%	-100%	-100%	not def.
RWE				
NW	0,7	0,5	0,1	0,0
RW	0,4	0,3	0,0	0,0
AW	0,1	0,0	0,0	0,0
	-79%	-99%	-100%	not def.
Vattenfall				
NW	1,3	1,2	0,7	0,0
RW	1,0	0,9	0,5	0,0
AW	0,7	0,6	0,2	0,0
	-47%	-52%	-68%	-100%
Fringe				
NW	2,7	2,6	2,1	0,8
RW	2,4	2,2	1,7	0,6
AW	2,0	1,9	1,5	0,4
	-25%	-26%	-29%	-45%

Table 5: Incentives to invest in new built power plants under imperfect competition.

Including the incentives of oligopolistic firms in the analysis does not improve the picture. To the contrary, incentives to invest are the weaker the larger the firm. In the advanced wind scenario the incentive to invest in natural gas fired gas turbines completely vanishes for the four dominant players. Combined cycle gas turbines also loose significantly in attractiveness, - although to a lesser extend compared with simple gas turbines. The two largest companies E.ON and RWE have no incentive to invest in combined cycle gas turbines already in the current *Real Wind* situation, and the advanced wind supply does not improve that incentive.

For the two smaller strategic companies, Vattenfall and EnBW, combined cycle gas turbines might still be an option, but compared to the scenario without wind energy supply their incentive to invest in this technology has been reduced by 68 and 41 percent respectively, bringing it down to almost zero for Vattenfall. Thus, the prospects for new gas fired units look bleak, especially when the commission of coal fired units is viable.

5 Summary and Discussion

We developed the electricity market model ESYMMETRY which applies different behavioral assumptions in regard to supply of firms and includes start up costs of thermal power plants. It turns out that a representation of the large electricity companies as Cournot quantity setters is more appropriate under our cost assumptions, and that hourly elasticities around one yield the closest results compared to the price history at the EEX.

We find that the current wind supply of 42.5 tera watt hours from Winter 2007 until autumn 2008 reduced the emissions of the sector by 13.6 million tons of CO_2. Moreover, the reduction of the spot market price of 0.37 euro cent per kilo watt crowded out about a third of a conventional production unit due to a unit of wind power. Consequently, the implied marginal abatement costs are more than 66 euro per ton of CO_2.

In order to assess the impact of the fluctuating character of the wind supply we additionally calculate a scenario in which the wind energy is assumed to be supplied constantly over time. We find that the real fluctuating wind supply is more effective in terms of emission reduction and less effective with regard to price reduction. Due to reduced crowding out of conventional production, the marginal abatement costs of a constant wind supply would increase to 69 euro per ton of CO_2.

In addition, we try to shed some light on the impact of an increased wind supply. We find that the price dampening effect per unit of wind energy supplied is likely to decrease while the emissions will be reduced more effectively. It turns out that the doubling of the wind supply will reduce emissions by more than 17 million tons of CO_2 and prices by only one third of a cent. Hence, the marginal abatement costs would decrease to about 60 euro per ton of CO_2 at current support tariff. This improvement of the effectiveness of the support policy is caused by a successive displacement of base load coal units with their relatively high carbon intensity. However, given the marginal abatement costs implied by the European emission trading system of currently 25 euro per ton of CO_2, the promotion of wind power by the FIT is still an expensive option to reduce emissions in the power sector.

Another central insight is gained in regard to the ability of the market to cope with the increased intermittent supply of wind power. We find that the incentives to invest in flexible power plants, e.g. natural gas fired gas turbines and combined cycle units, which are able to cope with strong fluctuations, seem to be not sufficient. Rather, the attractiveness of these units is greatly reduced by the development of wind supply. In particular, large strategic power supply firms do not have any incentive to invest in natural gas units. These findings call for a more market based approach to wind energy pricing[10]. If wind energy suppliers had to provide reliability as the market demands it, they would have an incentive to back up their units by complementary measures in order to avoid high costs of alternative procurement in weak wind load hours. In addition to own investment in flexible units, these measures could include demand management, interruptible supply contracts, or the acquisition of facilities for power storage.

The results in regard to price and emission effects of the wind energy supply which are obtained in our study are well below the effects calculated by other investigations which abstract from elastic electricity demand, e.g. Rathmann (2007), Sensfuß et al. (2008). However, even when compared to the results found in Traber and Kemfert (2009) who use a elasticity of demand of about 0.5 the market price and conventional production reductions obtained in the present paper are modest. One reason for the differences is that total production costs are higher when including start-up effects, and, thus the elasticities obtained by the calibration are higher, i.e. around one. The burden of the support system induced on final consumers might be another reason for the deviations. Therefore, the inclusion of the renewable support system could be a fruitful extension of the model.

The investigation of the economics of balancing measures is generally expected to gain further importance. Not only fluctuating wind power is contributing to the problem of reliability, but also other fluctuating supplies, e.g. from solar power. In addition, carbon capture and storage (CCS) will probably decrease the flexibility of coal fired units. While in a carbon constraint world RES and CCS have to accompany each other, their combination opens up questions in terms of reliability left for future research.

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